Alberta
ENERGY

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GAS ROYALTY CALCULATION INFORMATION BULLETIN

07-01

January 2007

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PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for November 2006, refer to Attachments 1, 1A, 2, 2A, and 3. These attachments are also available in Excel format.

B. NOTICES

New Meter Station Factors

The department has published in Information Letter 2007-02 new meter station factors as identified in Attachment 4. The meter station factors are effective for varying production periods between October 2002 and September 2006. These same receipt meter station factors have also been revised for the October 2006 production period, which will remain in effect for subsequent production periods until otherwise changed.

If you have any questions, please contact Bill Zanewick, Director Gas Royalty Valuation and Markets Division at (403) 297-5465 or e-mail at bill.zanewick@gov.ab.ca.

Expected AC2 Reports on the Registry

Effective Monday, February 5, 2007 and each Monday thereafter to May 28, 2007, expected capital cost allowance (AC2) reports will be available on the Registry for client access. The reports will be available in PDF, TXT and CSV formats.

Should you have any questions or concerns regarding AC2 expected reports or filings, please contact your Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin or contact Joey Dennis at (780) 422-9260.

Submission of Production Year 2006 Allowable Cost (AC) and Corporate Average Price Calculation (VA) Forms

Royalty clients are advised that Allowable Cost forms (AC1, AC2, AC3, AC4 and AC5) and Corporate Average Price calculation forms (VA2 and VA3) for the 2006 production year are due on the following dates:

Form Type	*Due Date*	*Penalty*
AC1	March 01, 2007	-
AC4	March 31, 2007	$200/Form/Year until received
VA2	April 15, 2007	$1,000/One time only
VA3	April 15, 2007	$1,000/One time only
AC2	April 30, 2007	$100/Form/Month until received
AC3	May 15, 2007	-
AC5	May 15, 2007	$100/Form/Month assessed when form is received

Please note that all allowable cost submissions (initial and amended filings for current and prior production years) by operators are required to be completed on the Registry. Although use of the Registry to file AC3 and AC5 documents is mandatory for operators, it remains voluntary for non-operators. However, non-operators are strongly encouraged to use the Registry to submit

and retrieve their AC3 and AC5 data. The business rules and submission method for VA2 and VA3 forms remain the same with notification from the department informing clients that their forms have been processed. Annual allowable cost forms are processed nightly except during an invoice run cycle. New facility cost centre set-ups which are processed within four hours of receipt will continue to be generated during an invoice run cycle. The Corporate Average Price forms are processed as they are received.

The department encourages timely submissions to allow sufficient turnaround time for corrections. Non-operators are particularly encouraged to file their Corporate Average Price forms timely by mail or direct delivery to the Calgary Information Centre. The font size on faxed forms must be 10 pt or greater and must not be bold. Penalties will apply where valid system acceptable forms are received past the due date. Barring department's responsibility, inability to submit annual cost forms on the Registry and/or illegible script will not reverse a penalty once imposed.

Should you have any questions or clarifications regarding these matters, please contact Joey Dennis at (780) 422-9260 or e-mail Joey.Dennis@gov.ab.ca.

2006 AC4 Form - Allowable Operating Costs

The operator of a Facility Cost Centre (FCC) that is tied to a designated facility, or is a processing type FCC tied to a non-designated facility that is a sweet or sour gas plant, is required to report annual operating costs on the AC4 submission to the department, describing the allowable operating costs of the FCC for each year. Should the form not be submitted, no operating costs for the FCC will be applied in the calculation of the Unit Operating Cost Rates (UOCR) for the following year.

The due date for the 2006 AC4 form is March 31, 2007. FCC operators are encouraged to submit their AC4 forms prior to the due date to allow for correction turnaround should rejections occur. Forms received after the due date are subject to penalty charges. The 2006 AC4 reminder notices will be sent to operators, via the Registry, identifying those FCCs for which an AC4 form is required. AC4 reminder notices will be loaded into the Registry on the following dates:

- February 23, 2007
- March 02, 2007
- March 09, 2007
- March 16, 2007

AC4 turnaround documents will not be produced as all corresponding data will be available on the Registry following processing of the data transfer files from the Mineral Revenue Information System (MRIS). AC4 rejection notices are also delivered to operators via the Registry.

Commencing the first week in March, a listing of outstanding AC4 forms will be published on the Natural Gas website's Royalty Related Information page under Royalty and Related Information Review. Please scroll to the updates near the bottom of the page and select Outstanding AC4s for 2006 to open the most recent listing. Updates should be monitored closely in order to resubmit rejected forms on or before March 31, 2007. Should you have any questions, please contact Joey Dennis, Program Support, at (780) 422-9260.

December 2006 Production Royalty Due Date is March 30, 2007

The royalty due date for December 2006 production issued in February 2007 is due on or before March 30, 2007. Section 18(3) of the Natural Gas Royalty Regulations, 2002 provides for payment of the royalty invoice issued in February (December production month) on or before the last day in which the offices of the department are open in March.

C. MONTHLY INFORMATION

November 2006 Royalty Due February 28

- **Royalty clients are to remit the total amount payable shown on the February 2007 Statement of Account by February 28, 2007.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The February 2007 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your November 2006 Invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of November 2006 if it is paid in full by February 28, 2007.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

  Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

December 2006 VA4 Due February 15

The VA4 forms for the production month of December 2006 are due in the department offices by February 15, 2007.

Note: If the due date (15th) falls on a non-business day, the next business day will apply as the due date for VA4 forms.

December 2006 Production Reporting

December 2006 production reporting is submitted through the Registry. The deadline for submission of SAF, OAF, and Volumetrics is posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Bulletin Board.

Changes to this calendar will be posted on the Registry web site home page in "Broadcast Messages."

Interest Rate January 2007

Alberta Energy's interest rate for January 2007 is 7.00%

October Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the October 2006 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$4,909,342.58	($2,802,442.40)	$2,106,900.18

October Penalty Charges

The revised penalty table below shows at the form level, the total penalty charges and reversals, for the October 2006 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2006/10
AC2	$55,900	($39,600)	$16,300
AC4	$1,800	($2,000)	($200)
AC5	$700	($24,900)	($24,200)
GR2	$0	$0	$0
NGL1	$1,000	$0	$1,000
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$400	$0	$400
Total	$59,800	($66,500)	($6,700)

Alberta Royalty Tax Credit Program Quarterly Rate

The Alberta Royalty Tax Credit Program is no longer in effect as of January 1, 2007. However, the Alberta Royalty Tax Credit rates for the past year were:

Third Quarter, 2006	.2500
Second Quarter, 2006	.2500
First Quarter, 2006	.2500
Fourth Quarter, 2005	.2500

For further information, please contact Alberta Finance, Information Services at (780) 427-3044. [Toll-free long distance is (780) 310-000-427-3044].

Gas Royalty Calculation Support

Gas Royalty Calculation staff will be available monthly to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to call Richard Stokl, Manager, Client Services (780-422-9258) or e-mail richard.stokl@gov.ab.ca two business days before the meeting date to arrange an appointment. The January through March schedule is as follows:

Where:

AMEC Place
Room 437, 801-6 Avenue SW
Calgary, Alberta
Phone: 403-297-8954
(Industry must go to the 3rd Floor Reception upon arrival to sign-in and be given a visitor tag)

When – 10 am to 3 pm

January 25, 2007
February 22, 2007
March 29, 2007

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role start date with no end date, then that BA can receive allocations from the stated start date forward.
- If a BA has a WIO role start and end date, then they can only receive allocations from the stated start date until the end date. Any allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive allocations at all.

Please contact Client Registry at (780) 422-1395 if you have any questions regarding the information supplied on this listing.

Projects/Blocks

If information is required on Projects or Blocks, please contact Isabelle Warwa at (780) 427-8952.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at (780) 422-1395.

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Historical Pricing and Royalty Data Correction

The 2003 Weighted Average OMAC – Type Charges and the 2003 Weighted Average Gas Reference Price was incorrect in the historical pricing and royalty data attachment in the March 2004, March 2005, and February 2006 Information Bulletins. The 2003 Weighted Average OMAC – Type Charges is $0.021 and the 2003 Weighted Average Gas Reference Price is $5.83. The internet versions of these bulletins now reflect the correct prices.

Should you have any questions, please contact Shellie Duiker at (780) 422-8083.

Revised Meter Station Factors

The department has published revised Meter Station Factors in Information Letter 2006-35, where Meter Station Factors for those prescribed effective October 2006 are identified.

If you have any questions, please contact Bill Zanewick, Director Gas Royalty Valuation and Markets Division at (403) 297-5465 or e-mail at bill.zanewick@gov.ab.ca.

Statutory Requirement and Recalculation of 2002 Royalty

A production year becomes statute barred on December 31st, four years after the end of a production year. Once a year has become statute barred, calculation or recalculation of royalty does not occur on a monthly basis.

Section 38 of the Mines and Minerals Act provides for recalculation of royalty that can be initiated in either of two ways:

a) On the department's initiative in conjunction with an audit or examination; or
b) At the request of a royalty payer.

Audits in Progress

Non-operator partners are advised that certain 2002 capital cost and custom processing adjustment factor (CPAF) and reporting discrepancy audits are currently in progress. Completion of the audits and royalty recalculations and assessments, if required, will occur in 2007. For a complete listing of the affected EUB facilities, refer to Attachment 5.

Royalty clients are also reminded that amendments received by the department in the fourth year following the production year may be subject to audit. If the amendments were received late in the fourth year and insufficient time was available for the department to commence a review of the amendments prior to the end of the year, the department reserves the right to commence the audit at the beginning of the fifth year.

If you have any questions, please contact Chris Lawton of the Compliance & Assurance group at (403) 297-6746.

Training Sessions

Allowable Cost Refresher
Client Services will be conducting two training sessions in Calgary on March 8, 2007 at the McDougall Centre, 412 7th St. S.W. We will be hosting a morning session from 10:00 a.m. until noon and an afternoon session from 1:30 to 3:30, the content of both sessions will be the same. Please call Patricia Janhsen at (780) 422-9351 by Wednesday February 28, 2007 to register for one of these sessions.

Royalty Adjustment Program for Deep Marginal Gas Wells
The department and Alberta Energy and Utilities Board (EUB) will be conducting a joint information session on the new royalty adjustment program. Four information sessions will be held on March 19 & 20 at McDougall Centre (412 – 7th St. S.W.). A morning session from 10:00 to 12:00 and an afternoon session from 1:30 to 3:30 will occur on each date. As the information provided may be of benefit to your engineers, please ensure they are informed of these training sessions. Spacing is limited thus to ensure you secure a seat you must register by Wednesday February 28, 2007. Please contact Patricia Janhsen at (780) 422-9351 to register.

To provide further clarification the following article has been modified from the original publication in the October 2006 Information Bulletin.

Termination of the Deep Gas Royalty Holiday Program (DGRHP) and Implementation of a new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW)

On August 22, 2006, Alberta Energy (DOE) announced the termination of the existing royalty holiday program for deep natural gas wells and the implementation of a new adjustment program for deep marginal natural gas wells as described in Information Letter 2006-26. The changes are effective as of September 1, 2006.

Phasing out the existing Deep Gas Royalty Holiday Program (DGRHP)
Wells that are drilled or deepened, before April 1, 2010, on a Crown Agreement that has a term commencement date (the date the mineral rights were acquired from the Crown) earlier than September 1, 2006 and meets the DGRHP criteria will continue to be eligible for exemption under the existing DGRHP, with the following exceptions:

- Oil and oil sands wells, which are spudded or commence drilling on or after September 1, 2006, are no longer eligible for exemption under the DGRHP.
- Commencing April 1, 2012 all wells that have remaining benefits under the DGRHP will have the benefits rolled into the new program, and will be subject to a minimum 5% royalty rate.

Clients who are eligible for an exemption under the DGRHP may elect to receive adjustments under the new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW) rather than receive an exemption under the DGRHP. The election must be made in writing by the Designated Representative identified on the Crown Agreement or by the well licensee prior to spudding or commencement of drilling and sent to:

Attention:
Gas Royalty Calculation Unit
Royalty Programs
8th floor NPP
9945 - 108 Street
Edmonton, AB T5K 2G6

The election must include the Crown Agreement number, the term commencement date and the legal land description. If a well license has been issued by the Alberta Energy and Utilities Board (EUB) the license number and the unique well identifier must also be included. In those situations where the well information is not available at the time of election, the Designated Representative or well licensee/operator must supply the well event identifier when it is available. The department will provide written notification regarding the well's eligibility.

New Program: Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW)

Highlights of Program

- The royalty adjustment begins on the first day of the month in which the royalty payable on gas production obtained from the well is due.
- Royalty adjustments must be used within 10 years following the finished drilling date applicable to the drilling or deepening of the well and will terminate if the well is abandoned.
- Wells are subject to a minimum 5% royalty rate each month.
- Royalty adjustments are limited to a maximum of $3,600,000 per well regardless of the number of producing zones.
- Determination of the royalty adjustment amount is based on the vertical and non-vertical (e.g. horizontal) depth of the well.
- Wells are subject to a production threshold.

Qualifying Criteria

To receive royalty adjustments under the RAPDMGW a well must:

- Be drilled or commence drilling on a Crown Agreement with a term commencement date on or after September 1, 2006,
- For Crown lands acquired prior to September 1, 2006, an election, as described above, may be made to qualify the well for this adjustment instead of a benefit under the DGRHP,
- Be drilled or deepened in a drilling spacing unit which is wholly outside the pool boundaries as designated by the EUB as at June 1, 1985 (i.e. outside an existing G-order),
- Be drilled into a producing zone, the top of which has a vertical depth greater than 2,500 meters,
- Not have average daily production (ADP) that exceeds the qualifying production rate (QPR) during each 12 month reporting period at any point during the adjustment entitlement. The first 12 month period commences on the effective date of the adjustment.

Wells that do not qualify for RAPDMGW include:

- A well completed in a drilling spacing unit containing wells that previously received a royalty exemption or royalty adjustment under prior regulations or Sections 10 -11 of Schedule 8 of the *Natural Gas Royalty Regulations, 2002*,
- A well whose production of crude oil or oil sands is exempt from royalty under the *Third Tier Exploration Well Royalty Exemption Regulation* and that exemption has not wholly been revoked,
- Off target wells,
- A well that produces oil either alone, or with gas at a gas-oil ratio of less than 1800:1,
- A well that produces oil sands, other than a gas well as defined in the *Oil and Gas Conservation Regulations.*

Determining whether a well qualifies

The process and technical analysis of whether a well qualifies for RAPDMGW will be completed in the same manner as DGRHP wells. An application is not required. If the department determines that the well meets all of the qualifying criteria, except the QPR, the department will perform a preliminary calculation of the ADP using available well production data at that time and compare this against the QPR described below.

If the ADP is below the calculated QPR at the initial calculation, the well will tentatively be approved for royalty adjustment under the program. A calculation of the QPR using production data for the 12 month reporting period will be completed when the data is available.

The calculation of the Average Daily Production (ADP) & Qualifying Production Rate (QPR)

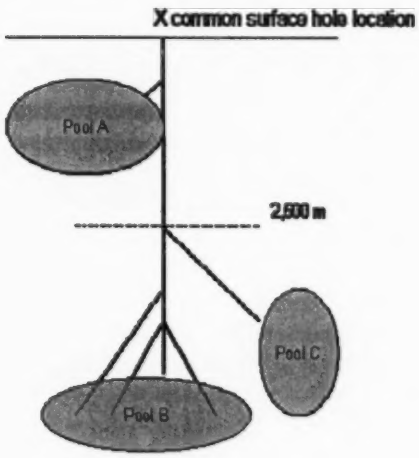
The ADP is determined by dividing the quantity of natural gas and field condensate from all the drilling occurrences that share the same surface location (production from all zones in a multi-zone well bore) within the 12 month reporting period and dividing this quantity by the number of days in the period (note these are not operating days but calendar days).

Note: Field condensate volumes will be expressed as a gas equivalent volume using a conversion rate of 1,000 cubic meters of natural gas per cubic meter of condensate.

The QPR will continue to be re-calculated, each reporting period for all non-statute barred years, for the entire 10 year entitlement period for the well regardless of whether the entire adjustment has been taken. If at any point the ADP exceeds the QPR, the entire adjustment will be revoked.

As shown in the diagram below the production included in the determination of the ADP would include all the drilling occurrences (each leg from the initial well is considered a drilling occurrence) that share this common surface hole location.

Diagram 1



The QPR was established to reference an economic threshold for wells at varying depths. For the initial six month analysis and first 12 month period the QPR is based on the following formula:

For wells drilled > 2,500 m but ≤ 3,500 m

$$QPR = \left[1.1327e^{3}m^{3} + \left\{ .0850e^{3}m^{3} \times \frac{(MD - 2500m)}{100m} \right\} \right] \times \left[\frac{MD}{100m} \right] \leq 3500 \text{ m}$$

For wells drilled > 3,500 m

$$QPR = \left[1.9822e^{3}m^{3} + \left\{ 0.1133e^{3}m^{3} \times \frac{(MD - 3500m)}{100m} \right\} \right] \times \left[\frac{MD}{100m} \right] > 3500 \text{ m}$$

Where:
QPR = the qualifying production rate for the well
MD = the measured depth of the well on the last day of the applicable period

The QPR for the second 12 month period will be 80% of the first period QPR and 68% of the first period QPR for the third and all subsequent 12 month periods.

If a well has an acid gas content of more than 15% by volume, the QPR may be adjusted using the following formula:

Adjusted QPR = QPR / [100% - (H_2S% + CO_2% - 15%)]

Where:
QPR = the qualifying production rate for the well
H_2S and CO_2 = the % of hydrogen sulphide and carbon dioxide contained in the raw gas stream by volume, respectively.

In cases where the well operator/licensee is seeking to have the adjusted QPR applied, it is their responsibility to provide documentation for the department's review, such as a gas analysis report signed by a professional engineer.

Determination of Royalty Adjustment
The royalty adjustment is the sum of the vertical and non-vertical adjustments. These adjustments are based on the corresponding vertical and non-vertical depths of the well, which are determined as follows.

The vertical depth is determined by using the distance from the surface location Kelley bushing to the shallower of the deepest point of the well or to the base of the natural gas producing interval in the deepest zone in paying quantities. The vertical depth, below 2,500 meters, is used in calculating the vertical adjustment as shown in Attachment 6.

The measured depth is the longest distance in meters measured along the well bore from the Kelley bushing to the lesser of the longest point of the well or to the base of a natural gas producing interval that is producing in paying quantities.

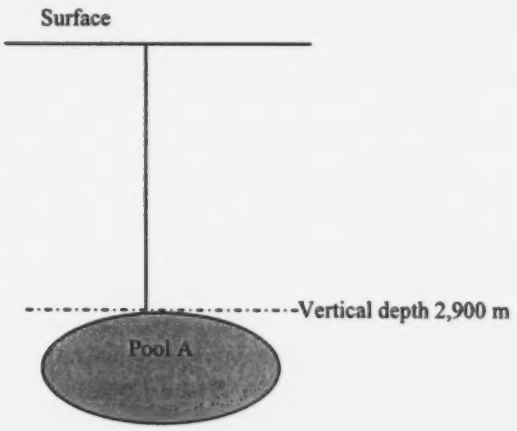
The non-vertical depth is the measured depth less the vertical depth of the well. The non-vertical depth is multiplied by $1000 per meter to determine the non-vertical adjustment.

A well that did not qualify for an adjustment previously but is subsequently deepened will be treated as a new well. In the case of an existing well that has received an adjustment and is subsequently deepened, a modified adjustment will be determined and a new initial QPR will be established.

The provincial weighted average gross up factor of 1.72392 will be applied against the adjustment amount determined by the formula above.

The following illustrations depict how the vertical depth, measured depth and non-vertical depth of wells are determined for the purpose of calculating an adjustment value.

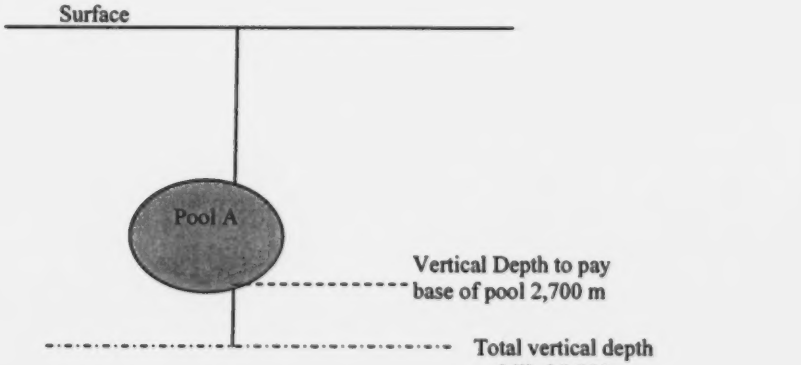
Figure 1 – Vertical well



Vertical depth = 2,900 m
Measured depth = 2,900 m
Non-vertical depth = 0

Vertical adjustment:
2,500 m = 0
400 m x $1,000 = $400,000
Non-vertical adjustment = $0
Total adjustment = $400,000

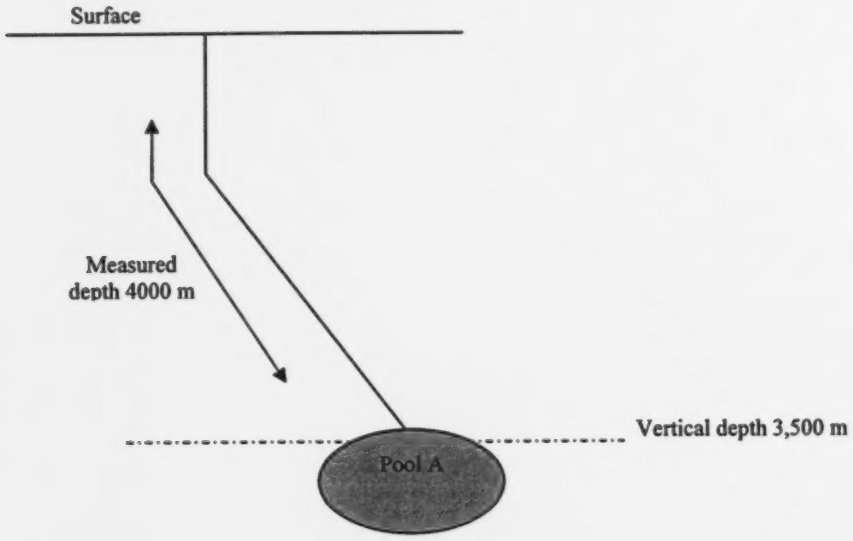
Figure 2 – A vertical well that extends past the pay base of the pool



Vertical depth = 2,700 m
Measured depth =2,700 m
Non-vertical depth = 0

Vertical adjustment:
2,500 m = $0
200 m x $1,000 = $200,000
Non-vertical adjustment = $0
Total adjustment = $200,000

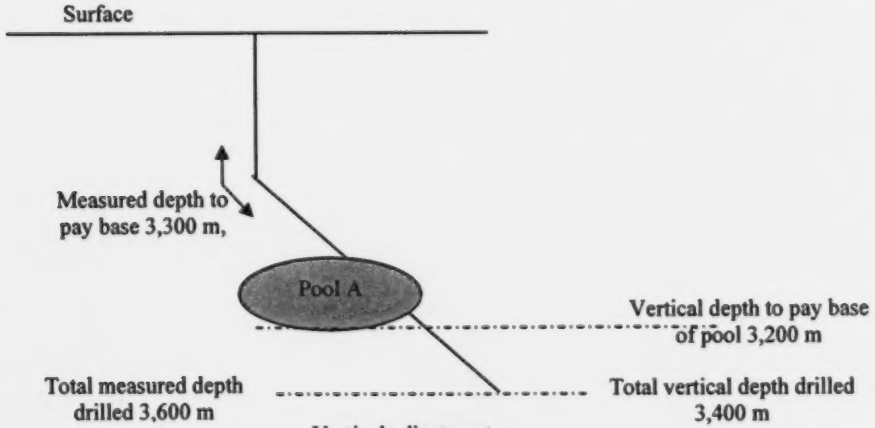
Figure 3 – Well with non-vertical depth



Vertical depth = 3,500 m
Measured depth = 4,000 m
Non-vertical depth = 500 m

Vertical adjustment:
3,500 m = $1,000,000
Non-vertical adjustment:
500 m x $1,000 = $500,000
Total adjustment = $1,500,000

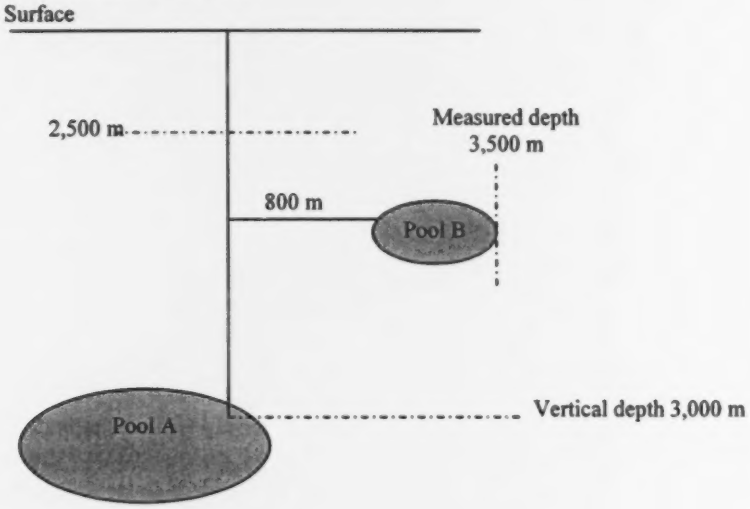
Figure 4 – Measured depth extends past the pay base of the pool


Surface
Measured depth to pay base 3,300 m,
Pool A
Vertical depth to pay base of pool 3,200 m
Total measured depth drilled 3,600 m
Total vertical depth drilled 3,400 m

Vertical adjustment:
3,000 m = $500,000
200 m x $1,000 = $200,000
Non-vertical adjustment:
100 m x $1,000 = $100,000
Total adjustment = $800,000

Vertical depth = 3,200 m
Measured depth =3,300 m
Non-vertical depth = 100 m

Figure 5 – Multi well bore



Vertical depth = 3,000 m
Measured depth = 3,500 m
Non-vertical depth = 500 m

Vertical adjustment:
3,000 m = $500,000
Non-vertical adjustment:
500 m x $1,000 = $500,000
Total adjustment = $1,000,000

Revocation of Royalty Adjustment if QPR exceeded

If at any point during the royalty adjustment entitlement period the ADP of the well exceeds the calculated QPR, the royalty adjustment will be revoked. The effective date of the revocation will be the royalty adjustment commencement date unless the well has been deepened after this date and the excess production is a result of the deepening. In this case the effective date for revocation will be the date the well was deepened.

Any Crown royalty charges that were offset by the adjustment will be reversed and royalty payable on the natural gas, field condensate and gas products will be recalculated as if the royalty adjustment never arose. Interest will apply to the recalculation of royalties.

If a royalty adjustment is revoked because the QPR was exceeded, a royalty client may request a review and must provide supporting documentation (e.g. Gas analysis report). The department will review the documentation and determine whether the royalty adjustment will be reinstated.

Processing time lines

The time line for processing royalty adjustments will be similar to those for the DGRHP. The department will inform the operator and licensee in writing when the well qualifies, the royalty adjustment amount, and other pertinent data. Clients may also track the progress of eligible wells on the internet through a well 'process status' spreadsheet similar to the spreadsheet for the DGRHP. See the Natural Gas Royalty Guidelines, 2006, Chapter V, Section 1 for a complete description of the available "process statuses."

Reporting
The department determines the monthly royalty adjustment amount based on the volumetric production and SAF/OAF allocation reporting. In order for a royalty adjustment to be applied against a well, the well must be reported at a single well level, except in the case where only a portion of the well qualifies for a royalty adjustment. In these situations the department will advise clients how to report the production.

Invoices/Statements
The department will automate the processes relating to this program in the near future. Until such time, the following processes will apply:

- In the first billing period, relating to the production reported for the well, the 5% royalty will not be charged. There will be a one month lag.
- In the following billing period the minimum 5% royalty rate will be calculated and charged. Interest will be charged on underpayments of royalties.
- RAPDMGW wells will appear on the royalty exemption statement as DGRHP wells. The remaining royalty adjustment balance shown on the exemption statement will be overstated by the 5% royalty which was not charged in the first billing period.
- Monthly, the department will send out a revised statement to all participants in the well showing the actual remaining royalty adjustment balance.

For additional information, please contact RoseAnn Summers, Manager, Royalty Billing at (780) 422-6684 or Tracy Wadson, Team Lead, Royalty Programs at (780) 422-9240. Email inquiries can be directed to RoyaltyPrograms@gov.ab.ca

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates, and Transportation Information are available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Calculation Information Bulletins and Information Letters are also available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

The Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Service teams. Listed below is the portfolio breakdown along with Client Service Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at (780) 644-1202.

Business Associate	Phone Number and E-mail Address	Team Lead
Numbered companies, A, B & L	(780) 644-1201 GRCST1@gov.ab.ca	Mary Spearing
C – G	(780) 644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	(780) 644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	(780) 644-1204 GRCST4@gov.ab.ca	Kamal Rajendra

Gas Royalty Reception: (780) 427-2962
Fax: (780) 427-3334 or (780) 422-8732
Alberta Toll Free: (780) 310-0000
Hours of operation are 8:15 a.m. to 4:30 p.m.
Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer.

Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets. You would not be entitled to information regarding business for TSP Exploration that is prior to the asset purchase.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-5514
Fax (403) 297-5400

Calgary Information Centre

300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-6324
Fax (403) 297-8954

Alberta Royalty Tax Credit Information

Alberta Finance, Tax and Revenue Administration
Tax Services
Telephone: (780) 427-3044
Alberta Toll Free: (780) 310-0000
Fax: (780) 427-5074
For further information, please contact Tax Services at (780) 427-9425.

Deen Khan
Director, Gas Royalty Calculation
Gas Development

Attachments

2006 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butane ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	9.52	9.56	9.56	9.33	9.11	9.10	9.14
FEB	7.38	7.36	7.36	7.58	7.58	7.58	7.59
MAR	6.47	6.46	6.46	6.67	6.71	6.74	6.76
APR	6.18	6.17	6.17	6.31	6.31	6.36	6.36
MAY	5.71	5.70	5.70	5.77	5.74	5.76	5.77
JUN	5.29	5.26	5.26	5.57	5.64	5.67	5.70
JUL	5.22	5.19	5.19	5.48	5.54	5.57	5.58
AUG	5.84	5.81	5.81	6.06	6.10	6.13	6.15
SEPT	5.12	5.12	5.12	5.14	5.09	5.12	5.13
OCT	4.40	4.33	4.33	4.82	5.00	5.03	5.06
NOV	6.51	6.46	6.46	6.86	6.96	7.00	7.01
DEC							

Natural Gas and NGLs Select Prices for 2006

Commodity	2006
New Methane	1.419 $/GJ
Old Methane	0.418 $/GJ
New Ethane	1.419 $/GJ
Old Ethane	0.418 $/GJ
Propane	1.419 $/GJ
Butane	1.419 $/GJ
Pentanes plus	50.73 $/m3

Royalty Factors for Pentanes plus

	Base	Marginal
New Pentanes	22	35
Old Pentanes	22	50

DETAIL OF THE NOVEMBER 2006 GAS AND ISC REFERENCE PRICES

	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	6.914	6.886	7.094	7.130	7.142	7.145
Deductions: Intra – Alberta Transportation	0.223	0.237	0.135	0.095	0.073	0.056
Marketing Allowance	0.011	0.011	0.011	0.011	0.011	0.011
Price Before Pipeline Factor	6.680	6.638	6.948	7.024	7.058	7.078
Pipeline Fuel/Loss Factor	.991	.991	.991	.991	.991	.991
Price before Special Adjustment	6.618	6.576	6.883	6.958	6.993	7.012
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	6.618	6.576	6.883	6.958	6.993	7.012
Amendments: Carry forward (from previous RP month)	-0.102	-0.116	-0.024	0.004	0.002	0.002
Prior Period Amendment Adjustment (current RP month)	-0.001	-0.001	0.001	0.000	0.000	0.000
Calculated RP after Amendments	6.515	6.459	6.860	6.962	6.995	7.014
NOVEMBER 2006 Reference Price	**6.51**	**6.46**	**6.86**	**6.96**	**7.00**	**7.01**
Difference = value carried forward to next RP month	0.005	-0.001	0.000	0.002	-0.005	0.004
Adjusted IATD (before Prior Period Amendments)	[redacted]	0.235	0.134	0.094	0.073	0.055
Prior period Amendments (IATD and Pipeline Fuel Loss)	[redacted]	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	[redacted]	0.235	0.134	0.094	0.073	0.055

2005 Weighted Average Reference Price ($/GJ)
7.935

2005 Weighted Average OMAC ($/GJ)
0.023

2006
NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Par Price ($/GJ)	Propane Floor Price ($/m3)	Butanes Reference Price ($/m3)	Butanes Par Price ($/GJ)	Butanes Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	9.33	9.33	289.22	9.11	240.07	394.52	9.10	329.84	484.39	477.02	27.53
FEB	7.58	7.58	248.16	7.58	213.28	370.63	7.58	279.57	468.40	441.89	29.48
MAR	6.67	6.67	254.40	6.71	213.86	362.89	6.74	272.66	468.85	457.27	31.39
APR	6.31	6.31	286.26	6.31	248.88	390.67	6.36	290.57	545.33	524.82	25.41
MAY	5.77	5.77	279.81	5.74	247.11	376.44	5.76	283.32	529.03	507.26	24.31
JUN	5.57	5.57	287.72	5.64	258.60	377.94	5.67	295.08	557.91	516.67	21.78
JUL	5.48	5.48	313.36	5.54	281.70	402.10	5.57	315.61	564.17	538.62	18.77
AUG	6.06	6.06	305.03	6.10	275.34	402.10	6.13	317.45	530.10	511.93	14.09
SEPT	5.14	5.14	269.07	5.09	240.91	366.43	5.12	268.30	443.64	429.71	16.45
OCT	4.82	4.82	263.50	5.00	228.69	320.32	5.03	254.10	431.87	410.21	14.99
NOV	6.86	6.86	267.41	6.96	232.98	311.40	7.00	255.81	399.49	397.29	9.05
DEC											

ANNUAL SULPHUR DEFAULT PRICE				
2001	2002	2003	2004	2005
$0.28	$6.74	$30.97	$31.98	$33.98

2006
NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a) REGION				PROPANE AND BUTANE (b) REGION				PENTANES PLUS, PROPANE & BUTANE (c) REGION				FRAC. ALLOW. (per m3)
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	-0.90	13.92	10.05	18.08	18.72	-1.58	-33.18	-18.57	17.78	14.75	35.26	16.39	15.50
FEB	24.88	25.25	34.62	26.47	10.17	-2.24	-57.23	-19.17	18.42	13.68	31.79	18.91	15.50
MAR	14.23	10.00	32.47	4.43	12.33	6.56	3.05	-2.25	20.08	16.58	22.76	19.67	15.50
APR	16.82	16.81	36.92	26.20	8.13	4.05	4.42	3.86	18.80	24.73	22.81	27.82	15.50
MAY	21.44	17.83	34.47	26.88	7.50	0.28	-5.71	1.91	17.91	17.74	17.30	23.36	15.50
JUN	43.47	23.21	58.72	48.53	11.04	8.25	3.62	3.89	39.43	25.73	31.26	24.21	15.50
JUL	25.15	20.49	48.28	19.48	14.52	5.93	12.23*	6.56	31.03	17.24	30.26	23.09	15.50
AUG	22.34	13.57	22.42	12.02	6.13	-0.40	-13.90	4.17	5.48	6.47	11.26	14.65	15.50
SEPT	7.15	14.00	37.82	22.86	15.20	-0.29	11.19*	-0.03	2.90	5.70	0.43	12.06	15.50
OCT	17.73	32.23	44.58	8.15	18.24	1.49	17.20	8.30	16.16	15.89	28.60	14.69	15.50
NOV	-0.97	8.10	7.39	-2.38	20.47	-0.31	15.65*	7.12	3.83	7.19	21.79	6.17	15.50
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butane obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

* Current month calculated allowance is based on an estimate.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS

NGL REFERENCE PRICES	NOVEMBER 2006		
	Propane	*Butanes*	*Pentanes*
Price before amendments	269.892415	315.067667	405.180426
Opening Rollover (from prior business mth)	-0.004364	-0.002898	-0.004392
Prior Period Amendment Adj. (NGL-1)	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	-2.475126	-3.662002	-5.682189
Published Reference Price	**267.41**	**311.40**	**399.49**

TRANSPORTATION ALLOWANCES	NOVEMBER 2006											
	Pentanes Plus				Propane and Butane				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	-0.002158	0.001562	0.002695	-0.003250	-0.002836	-0.002988	-0.002912	-0.003264	0.000500	0.002772	0.001794	0.002559
Prior Period Amendment Adj. (NGL1)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	1.179924	-1.863378	-4.999523	-2.179654	-2.769473	-2.963792	-2.293047	-2.580310	-3.374408	-2.334426	-2.321198	-3.495892
Total Amendment Effect	1.177766	-1.861816	-4.996828	-2.182904	-2.772309	-2.966780	-2.295959	-2.583574	-3.373908	-2.331654	-2.319404	-3.493333
Calculated Transp. Differential	-2.144873	9.957494	12.382763	-0.192361	23.242870	2.654739	17.941034*	9.705132	7.199659	9.522061	24.113451	9.662313
Calculated Transp. Differential after Total Amendments	-0.967107	8.095678	7.385935	-2.375265	20.470561	-0.312041	15.645075*	7.121558	3.825751	7.190407	21.794047	6.168980
Published Transportation Allowance	**-0.97**	**8.10**	**7.39**	**-2.38**	**20.47**	**-0.31**	**15.65***	**7.12**	**3.83**	**7.19**	**21.79**	**6.17**

*Any estimates represented by (*) are calculated as the weighted average of the other regions for the same spec product transportation allowance, since the region is zero. The weightings are based on the previous year's production.

2006
ROYALTY RATES

MONTH	METHANE-OLD (% per GJ)	METHANE-NEW (% per GJ)	ETHANE - OLD (% per GJ)+	ETHANE - NEW (% per GJ)	PROPANE (% per m^3)	BUTANES (% per m^3)	PENTANES – OLD (POL) (% per m^3)	PENTANES - NEW (PNE) (% per m^3)
JAN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.02226	33.61748
FEB	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.78553	33.50757
MAR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.89365	33.55777
APR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.29347	33.74340
MAY	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.19978	33.69990
JUN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.25078	33.72358
JUL	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.36282	33.77559
AUG	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.22532	33.71176
SEPT	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.69442	33.46527
OCT	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.53729	33.39231
NOV	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.42468	33.34003
DEC								

METER STATION FACTORS
FROM STATED PRODUCTION MONTH

RECEIPT METER STATION ID	RECEIPT METER STATION NAME	RECEIPT METER STATION LOCATION	RECEIPT METER STATION FACTOR	PIPELINE COMPANY NAME	PIPELINE COMPANY ID	PRODUCTION MONTH EFFECTIVE	PRODUCTION MONTH INEFFECTIVE
0800297	SOUTH POUCE SALES	13 - 12 - 078 - 13 - 6	0.00	WESTCOAST (ALBERTA)	0135	October-2002	October-2003
0800297	SOUTH POUCE SALES	13 - 12 - 078 - 13 - 6	0.08	WESTCOAST (ALBERTA)	0135	October-2003	October-2004
0800297	SOUTH POUCE SALES	13 - 12 - 078 - 13 - 6	0.03	WESTCOAST (ALBERTA)	0135	October-2004	October-2005
0800297	SOUTH POUCE SALES	13 - 12 - 078 - 13 - 6	0.10	WESTCOAST (ALBERTA)	0135	October-2005	October-2006
0800297	SOUTH POUCE SALES	13 - 12 - 078 - 13 - 6	0.27	WESTCOAST (ALBERTA)	0135	October-2006	January-3000
0001170	CARBON	00 - 16 - 029 - 22 - 4	0.81	NOVA - NGTL	0TB3	October-2004	October-2005
0001170	CARBON	00 - 16 - 029 - 22 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0001170	CARBON	00 - 16 - 029 - 22 - 4	0.70	NOVA - NGTL	0TB3	October-2006	January-3000
0001332	AECO C	01 - 04 - 019 - 09 - 4	0.81	NOVA - NGTL	0TB3	October-2004	October-2005
0001332	AECO C	01 - 04 - 019 - 09 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0001332	AECO C	01 - 04 - 019 - 09 - 4	0.68	NOVA - NGTL	0TB3	October-2006	January-3000
0001475	DUHAMEL	00 - 31 - 045 - 20 - 4	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0001704	MEADOW CREEK	14 - 04 - 081 - 09 - 4	1.27	NOVA - NGTL	0TB3	February-2006	October-2006
0001704	MEADOW CREEK	14 - 04 - 081 - 09 - 4	1.38	NOVA - NGTL	0TB3	October-2006	January-3000
0001751	CROSSFIELD EAST #2	02 - 23 - 028 - 01 - 5	0.81	NOVA - NGTL	0TB3	October-2004	October-2005
0001751	CROSSFIELD EAST #2	02 - 23 - 028 - 01 - 5	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0001751	CROSSFIELD EAST #2	02 - 23 - 028 - 01 - 5	0.71	NOVA - NGTL	0TB3	October-2006	January-3000
0001795	JANUARY CREEK	00 - 34 - 054 - 14 - 5	0.94	NOVA - NGTL	0TB3	October-2004	October-2005
0001795	JANUARY CREEK	00 - 34 - 054 - 14 - 5	0.92	NOVA - NGTL	0TB3	October-2005	October-2006
0001795	JANUARY CREEK	00 - 34 - 054 - 14 - 5	0.90	NOVA - NGTL	0TB3	October-2006	January-3000
0001799	JARVIE NORTH	16 - 33 - 064 - 01 - 5	1.23	NOVA - NGTL	0TB3	May-2006	October-2006
0001799	JARVIE NORTH	16 - 33 - 064 - 01 - 5	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0001821	SEVERN CREEK	07 - 07 - 025 - 20 - 4	0.81	NOVA - NGTL	0TB3	October-2004	October-2005
0001821	SEVERN CREEK	07 - 07 - 025 - 20 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0001821	SEVERN CREEK	07 - 07 - 025 - 20 - 4	0.68	NOVA - NGTL	0TB3	October-2006	January-3000
0078203	Chancellor	02 - 24 - 023 - 20 - 4	0.81	NOVA - NGTL	0TB3	October-2004	October-2005
0078203	Chancellor	02 - 24 - 023 - 20 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0078203	Chancellor	02 - 24 - 023 - 20 - 4	0.68	NOVA - NGTL	0TB3	October-2006	January-3000
0085022	Grace Creek South	07 - 18 - 040 - 09 - 5	0.86	NOVA - NGTL	0TB3	October-2005	October-2006
0085022	Grace Creek South	07 - 18 - 040 - 09 - 5	0.82	NOVA - NGTL	0TB3	October-2006	January-3000
0085389	Davey Lake	04 - 17 - 034 - 26 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0085389	Davey Lake	04 - 17 - 034 - 26 - 4	0.73	NOVA - NGTL	0TB3	October-2006	January-3000
0085403	Highland Ranch	08 - 33 - 032 - 24 - 4	0.89	NOVA - NGTL	0TB3	October-2005	October-2006
0085403	Highland Ranch	08 - 33 - 032 - 24 - 4	0.87	NOVA - NGTL	0TB3	October-2006	January-3000
0085638	Ferintosh South	- 17 - 044 - 21 - 4	1.33	NOVA - NGTL	0TB3	October-2005	October-2006
0085638	Ferintosh South	- 17 - 044 - 21 - 4	1.26	NOVA - NGTL	0TB3	October-2006	January-3000
0085677	Rumsey North #2	12 - 04 - 034 - 20 - 4	1.19	NOVA - NGTL	0TB3	October-2005	October-2006
0085677	Rumsey North #2	12 - 04 - 034 - 20 - 4	1.17	NOVA - NGTL	0TB3	October-2006	January-3000
0085678	Torrington East #2	05 - 11 - 033 - 26 - 4	0.77	NOVA - NGTL	0TB3	October-2005	October-2006
0085678	Torrington East #2	05 - 11 - 033 - 26 - 4	0.72	NOVA - NGTL	0TB3	October-2006	January-3000
0085845	Nosehill Creek North	01 - 01 - 057 - 22 - 5	0.92	NOVA - NGTL	0TB3	October-2005	October-2006
0085845	Nosehill Creek North	01 - 01 - 057 - 22 - 5	0.90	NOVA - NGTL	0TB3	October-2006	January-3000

RECEIPT METER STATION ID	RECEIPT METER STATION NAME	RECEIPT METER STATION LOCATION	RECEIPT METER STATION FACTOR	PIPELINE COMPANY NAME	PIPELINE COMPANY ID	PRODUCTION MONTH EFFECTIVE	PRODUCTION MONTH INEFFECTIVE
0086448	Big Eddy	07 - 19 - 054 - 19 - 5	0.90	NOVA - NGTL	0TB3	October-2005	October-2006
0086448	Big Eddy	07 - 19 - 054 - 19 - 5	0.88	NOVA - NGTL	0TB3	October-2006	January-3000
0086450	Big Eddy Interconnection	07 - 19 - 054 - 01 - 5	0.90	NOVA - NGTL	0TB3	October-2005	October-2006
0086450	Big Eddy Interconnection	07 - 19 - 054 - 01 - 5	0.88	NOVA - NGTL	0TB3	October-2006	January-3000
0087581	Galt Island	09 - 20 - 014 - 08 - 4	0.84	NOVA - NGTL	0TB3	December-2005	October-2006
0087581	Galt Island	09 - 20 - 014 - 08 - 4	0.82	NOVA - NGTL	0TB3	October-2006	January-3000
0087582	Big Valley	02 - 31 - 034 - 20 - 4	1.11	NOVA - NGTL	0TB3	January-2006	October-2006
0087582	Big Valley	02 - 31 - 034 - 20 - 4	1.12	NOVA - NGTL	0TB3	October-2006	January-3000
0087583	Boggy Hall	08 - 08 - 047 - 09 - 5	0.81	NOVA - NGTL	0TB3	December-2005	October-2006
0087583	Boggy Hall	08 - 08 - 047 - 09 - 5	0.79	NOVA - NGTL	0TB3	October-2006	January-3000
0088305	Doig River	02 - 30 - 090 - 12 - 6	1.21	NOVA - NGTL	0TB3	February-2006	October-2006
0088305	Doig River	02 - 30 - 090 - 12 - 6	1.24	NOVA - NGTL	0TB3	October-2006	January-3000
0088336	Squirrel Mountain	02 - 18 - 086 - 01 - 6	1.20	NOVA - NGTL	0TB3	March-2006	October-2006
0088336	Squirrel Mountain	02 - 18 - 086 - 01 - 6	1.22	NOVA - NGTL	0TB3	October-2006	January-3000
0088342	Ridgevalley	09 - 21 - 071 - 26 - 5	0.97	NOVA - NGTL	0TB3	April-2006	October-2006
0088342	Ridgevalley	09 - 21 - 071 - 26 - 5	1.03	NOVA - NGTL	0TB3	October-2006	January-3000
0088374	Lavesta	12 - 22 - 042 - 03 - 5	0.81	NOVA - NGTL	0TB3	March-2006	October-2006
0088374	Lavesta	12 - 22 - 042 - 03 - 5	0.81	NOVA - NGTL	0TB3	October-2006	January-3000
0088504	Maddenville	08 - 15 - 063 - 25 - 5	1.07	NOVA - NGTL	0TB3	March-2006	October-2006
0088504	Maddenville	08 - 15 - 063 - 25 - 5	1.09	NOVA - NGTL	0TB3	October-2006	January-3000
0088505	Resthaven	07 - 11 - 060 - 03 - 6	0.96	NOVA - NGTL	0TB3	April-2006	October-2006
0088505	Resthaven	07 - 11 - 060 - 03 - 6	1.02	NOVA - NGTL	0TB3	October-2006	January-3000
0088751	Duvernay	04 - 23 - 055 - 12 - 4	1.11	NOVA - NGTL	0TB3	March-2006	October-2006
0088751	Duvernay	04 - 23 - 055 - 12 - 4	1.11	NOVA - NGTL	0TB3	October-2006	January-3000
0088759	Mega River	02 - 03 - 113 - 12 - 6	1.27	NOVA - NGTL	0TB3	March-2006	October-2006
0088759	Mega River	02 - 03 - 113 - 12 - 6	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0088864	Kotcho	14 - 02 - 114 - 12 - 6	1.23	NOVA - NGTL	0TB3	April-2006	October-2006
0088864	Kotcho	14 - 02 - 114 - 12 - 6	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0088865	Mega River #2	02 - 03 - 113 - 12 - 6	1.27	NOVA - NGTL	0TB3	March-2006	October-2006
0088865	Mega River #2	02 - 03 - 113 - 12 - 6	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0088869	Shekilie River East	03 - 08 - 117 - 10 - 6	1.27	NOVA - NGTL	0TB3	March-2006	October-2006
0088869	Shekilie River East	03 - 08 - 117 - 10 - 6	1.33	NOVA - NGTL	0TB3	October-2006	January-3000
0089599	MacIntosh Lake	02 - 20 - 062 - 07 - 5	1.08	NOVA - NGTL	0TB3	May-2006	October-2006
0089599	MacIntosh Lake	02 - 20 - 062 - 07 - 5	1.16	NOVA - NGTL	0TB3	October-2006	January-3000
0089771	Cattail Lake South	06 - 06 - 072 - 25 - 5	0.95	NOVA - NGTL	0TB3	July-2006	October-2006
0089771	Cattail Lake South	06 - 06 - 072 - 25 - 5	1.01	NOVA - NGTL	0TB3	October-2006	January-3000
0089837	Resthaven North	04 - 21 - 060 - 02 - 6	0.95	NOVA - NGTL	0TB3	July-2006	October-2006
0089837	Resthaven North	04 - 21 - 060 - 02 - 6	1.01	NOVA - NGTL	0TB3	October-2006	January-3000
0090212	Veda	15 - 07 - 088 - 12 - 6	1.14	NOVA - NGTL	0TB3	July-2006	October-2006
0090212	Veda	15 - 07 - 088 - 12 - 6	1.23	NOVA - NGTL	0TB3	October-2006	January-3000
0090325	Shady Oak Interconnection	14 - 11 - 062 - 27 - 5	0.95	NOVA - NGTL	0TB3	October-2006	January-3000
0090403	Chapel Rock	- 32 - 008 - 02 - 5	0.66	NOVA - NGTL	0TB3	August-2006	October-2006
0090403	Chapel Rock	- 32 - 008 - 02 - 5	0.68	NOVA - NGTL	0TB3	October-2006	January-3000
0090442	Kersey #2	04 - 15 - 028 - 26 - 4	0.67	NOVA - NGTL	0TB3	August-2006	October-2006
0090442	Kersey #2	04 - 15 - 028 - 26 - 4	0.68	NOVA - NGTL	0TB3	October-2006	January-3000

RECEIPT METER STATION ID	RECEIPT METER STATION NAME	RECEIPT METER STATION LOCATION	RECEIPT METER STATION FACTOR	PIPELINE COMPANY NAME	PIPELINE COMPANY ID	PRODUCTION MONTH EFFECTIVE	PRODUCTION MONTH INEFFECTIVE
0090444	Eaglesham South	15 - 25 - 076 - 26 - 5	0.98	NOVA - NGTL	0TB3	August-2006	October-2006
0090444	Eaglesham South	15 - 25 - 076 - 26 - 5	1.04	NOVA - NGTL	0TB3	October-2006	January-3000
0090565	Mayberne	11 - 21 - 055 - 20 - 5	0.85	NOVA - NGTL	0TB3	September-2006	October-2006
0090565	Mayberne	11 - 21 - 055 - 20 - 5	0.89	NOVA - NGTL	0TB3	October-2006	January-3000
0090568	Chickadee Creek No. 2	04 - 33 - 060 - 13 - 5	1.02	NOVA - NGTL	0TB3	October-2006	January-3000
0091231	Lamerton South	04 - 31 - 041 - 20 - 4	0.86	NOVA - NGTL	0TB3	October-2006	January-3000
0085312	Blue Rapids Group (#4171)	06 - 02 - 048 - 09 - 5	1.02	ATCO PIPELINES NORTH	0Z6J	October-2005	October-2006
0085312	Blue Rapids Group (#4171)	06 - 02 - 048 - 09 - 5	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0086653	Weasel Creek Receipt Station (#4328)	04 - 20 - 057 - 21 - 4	1.02	ATCO PIPELINES NORTH	0Z6J	October-2005	October-2006
0086653	Weasel Creek Receipt Station (#4328)	04 - 20 - 057 - 21 - 4	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0089448	Rose Creek Rec Stn (# 4594)	05 - 02 - 048 - 08 - 5	1.02	ATCO PIPELINES NORTH	0Z6J	March-2006	October-2006
0089448	Rose Creek Rec Stn (# 4594)	05 - 02 - 048 - 08 - 5	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0090189	Fishnet Receipt Station	06 - 29 - 051 - 25 - 5	1.02	ATCO PIPELINES NORTH	0Z6J	June-2006	October-2006
0090189	Fishnet Receipt Station	06 - 29 - 051 - 25 - 5	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0091304	Boulder Receipt Stn (# 4659)	08 - 27 - 046 - 22 - 4	1.02	ATCO PIPELINES NORTH	0Z6J	September-2006	October-2006
0091304	Boulder Receipt Stn (# 4659)	08 - 27 - 046 - 22 - 4	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0091652	Prairie Creek Receipt Stn (#4698)	16 - 26 - 060 - 05 - 6	1.02	ATCO PIPELINES NORTH	0Z6J	September-2006	October-2006
0091652	Prairie Creek Receipt Stn (#4698)	16 - 26 - 060 - 05 - 6	1.11	ATCO PIPELINES NORTH	0Z6J	October-2006	January-3000
0086654	Crocodile Lake Receipt (#14088)	- 31 - 012 - 25 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0086654	Crocodile Lake Receipt (#14088)	- 31 - 012 - 25 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0087567	Snake Creek Receipt (# 14140)	12 - 28 - 016 - 24 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	November-2005	October-2006
0087567	Snake Creek Receipt (# 14140)	12 - 28 - 016 - 24 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0089180	Forty Mile Coulee Rec Stn (14553)	01 - 03 - 009 - 12 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	March-2006	October-2006
0089180	Forty Mile Coulee Rec Stn (14553)	01 - 03 - 009 - 12 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0089447	North Antonoid Receipt Stn #14554	13 - 29 - 010 - 13 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	March-2006	October-2006
0089447	North Antonoid Receipt Stn #14554	13 - 29 - 010 - 13 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611501	PAN CANADIAN REDLAND	00 - 08 - 029 - 22 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611501	PAN CANADIAN REDLAND	00 - 08 - 029 - 22 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611507	STRATHM. #2 N PHASE 1	09 - 27 - 024 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0611507	STRATHM. #2 N PHASE 1	09 - 27 - 024 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611507	STRATHM. #2 N PHASE 1	09 - 27 - 024 - 25 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611508	STRATHMORE # 2 S. PHASE 2	06 - 28 - 023 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0611508	STRATHMORE # 2 S. PHASE 2	06 - 28 - 023 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611508	STRATHMORE # 2 S. PHASE 2	06 - 28 - 023 - 25 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611509	PAN CANADIAN-CARSELAND	01 - 29 - 022 - 26 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0611509	PAN CANADIAN-CARSELAND	01 - 29 - 022 - 26 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611509	PAN CANADIAN-CARSELAND	01 - 29 - 022 - 26 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611530	GAYFORD SOUTH PAN CAN	12 - 35 - 026 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0611530	GAYFORD SOUTH PAN CAN	12 - 35 - 026 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611530	GAYFORD SOUTH PAN CAN	12 - 35 - 026 - 25 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0611595	KEOMA RECEIPT STATION	16 - 18 - 026 - 26 - 4	1.00	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0611595	KEOMA RECEIPT STATION	16 - 18 - 026 - 26 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0611595	KEOMA RECEIPT STATION	16 - 18 - 026 - 26 - 4	1.09	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0612515	DEADHORSE RECEIPT STATION	00 - 14 - 023 - 27 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0612515	DEADHORSE RECEIPT STATION	00 - 14 - 023 - 27 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000

RECEIPT METER STATION ID	RECEIPT METER STATION NAME	RECEIPT METER STATION LOCATION	RECEIPT METER STATION FACTOR	PIPELINE COMPANY NAME	PIPELINE COMPANY ID	PRODUCTION MONTH EFFECTIVE	PRODUCTION MONTH INEFFECTIVE
0612548	Benaman	12 - 30 - 024 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0612548	Benaman	12 - 30 - 024 - 25 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0612548	Benaman	12 - 30 - 024 - 25 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0612550	Sharples Receipt Station	08 - 17 - 029 - 22 - 4	1.00	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0612550	Sharples Receipt Station	08 - 17 - 029 - 22 - 4	1.04	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0612550	Sharples Receipt Station	08 - 17 - 029 - 22 - 4	1.11	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0679201	CANTERRA ENTICE	00 - 24 - 028 - 24 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0679201	CANTERRA ENTICE	00 - 24 - 028 - 24 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0679201	CANTERRA ENTICE	00 - 24 - 028 - 24 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0680210	PAN CDN. ENTICE	10 - 07 - 028 - 23 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0680210	PAN CDN. ENTICE	10 - 07 - 028 - 23 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0680210	PAN CDN. ENTICE	10 - 07 - 028 - 23 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000
0680230	"ENTICE ""A"""	00 - 05 - 028 - 24 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2004	October-2005
0680230	"ENTICE ""A"""	00 - 05 - 028 - 24 - 4	0.97	ATCO PIPELINES SOUTH	0Z7N	October-2005	October-2006
0680230	"ENTICE ""A"""	00 - 05 - 028 - 24 - 4	1.03	ATCO PIPELINES SOUTH	0Z7N	October-2006	January-3000

2002 Capital Cost Audits in Progress at December 31, 2006

AB GP 0001004	AB GP 0001343	AB GP 0001669	AB GS 0002517
AB GP 0001013	AB GP 0001345	AB GP 0001683	AB GS 0002570
AB GP 0001024	AB GP 0001351	AB GP 0001686	AB GS 0002652
AB GP 0001034	AB GP 0001357	AB GP 0001692	AB GS 0002653
AB GP 0001057	AB GP 0001360	AB GP 0001696	AB GS 0002669
AB GP 0001067	AB GP 0001364	AB GP 0001697	AB GS 0002700
AB GP 0001070	AB GP 0001380	AB GP 0001698	AB GS 0002751
AB GP 0001084	AB GP 0001383	AB GP 0001730	AB GS 0002800
AB GP 0001101	AB GP 0001391	AB GP 0001746	AB GS 0002848
AB GP 0001107	AB GP 0001392	AB GP 0001775	AB GS 0002880
AB GP 0001112	AB GP 0001417	AB GP 0001789	AB GS 0002889
AB GP 0001130	AB GP 0001427	AB GP 0001853	AB GS 0002988
AB GP 0001134	AB GP 0001468	AB GP 0001858	AB GS 0003030
AB GP 0001135	AB GP 0001497	AB GP 0001862	AB GS 0003280
AB GP 0001139	AB GP 0001506	AB GP 0001874	AB GS 0003333
AB GP 0001141	AB GP 0001511	AB GP 0001875	AB GS 0003632
AB GP 0001144	AB GP 0001520	AB GP 0001880	AB GS 0003692
AB GP 0001147	AB GP 0001522	AB GP 0001886	AB GS 0003739
AB GP 0001149	AB GP 0001524	AB GP 0001892	AB GS 0004088
AB GP 0001156	AB GP 0001532	AB GP 0001895	AB GS 0004165
AB GP 0001159	AB GP 0001548	AB GP 0001962	AB GS 0004226
AB GP 0001163	AB GP 0001561	AB GP 0001976	AB GS 0004263
AB GP 0001172	AB GP 0001566	AB GP 0001984	AB GS 0004274
AB GP 0001184	AB GP 0001577	AB GP 0001997	AB GS 0004364
AB GP 0001202	AB GP 0001609	AB GS 0002207	AB GS 0004432
AB GP 0001217	AB GP 0001624	AB GS 0002282	AB GS 0004510
AB GP 0001222	AB GP 0001629	AB GS 0002323	AB GS 0004538
AB GP 0001224	AB GP 0001630	AB GS 0002369	AB GS 0004568
AB GP 0001270	AB GP 0001634	AB GS 0002382	AB GS 0004585
AB GP 0001292	AB GP 0001645	AB GS 0002392	AB GS 0004587
AB GP 0001296	AB GP 0001664	AB GS 0002396	AB GS 0004649
AB GP 0001316	AB GP 0001666	AB GS 0002443	AB GS 0006052
AB GP 0001322	AB GP 0001667	AB GS 0002491	AB GS 0006055
AB GP 0001326	AB GP 0001668	AB GS 0002516	

2002 Otherwise Flared Solution Gas S1 Production to Allocation Imbalances

AB GP 0001122
AB GP 0001296
AB GP 0001585
AB GP 0001698
AB GP 0001794
AB GP 0001892
AB GS 0006226

2002 Deep Gas Royalty Holiday Program

Well ID	Operator	Operator Name
100 11 07 012 01 W5 00	0J3J	Marathon International Petroleum Canada Ltd.
100 11 07 012 01 W5 01	0J5Z	BP Canada Energy
100 11 07 012 01 W5 02	0CW8	Compton Petroleum Corp.
100 11 07 012 01 W5 03	0AL2	Marathon Canada Ltd.
100 11 07 012 01 W5 04	0R46	Husky Oil Operations Limited
100 05 25 058 20 W5 00	0060	BP Canada Energy Co.
100 11 29 055 19 W5 00	0060	BP Canada Energy Co.
100 16 04 037 08 W5 00	0060	BP Canada Energy Co.
100 03 29 065 08 W6 02	0060	BP Canada Energy Co.
100 01 11 057 20 W5 04	0060	BP Canada Energy Co.
100 10 28 063 12 W6 00	0060	BP Canada Energy Co.
100 07 01 065 08 W6 00	0060	BP Canada Energy Co.
100 01 09 064 26 W5 02	0045	Chevron Canada Ltd.
100 12 19 064 26 W5 00	0045	Chevron Canada Ltd.
100 08 18 058 20 W5 03	0045	Chevron Canada Ltd.
100 05 01 059 21 W5 00	0045	Chevron Canada Ltd.
100 16 19 065 03 W6 03	0045	Chevron Canada Ltd.
102 11 03 045 12 W5 00	0FW6	ConocoPhillips Canada Resources Corp.
100 15 36 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 15 22 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 15 36 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 15 22 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 08 28 030 01 W5 00	0KT5	Esprit Exploration Ltd.
100 13 14 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 11 12 031 01 W5 00	0KT5	Esprit Exploration Ltd.
100 14 10 042 15 W5 03	0R46	Husky Oil Operations Limited
100 06 13 057 02 W6 02	0R46	Husky Oil Operations Limited
102 11 03 045 12 W5 00	0YD9	Keyspan Energy Canada Inc,
100 06 28 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 13 22 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 01 29 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 02 32 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 08 27 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 10 17 055 23 W5 00	A06X	3075704 Nova Scotia Co.
100 14 21 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 01 29 056 23 W5 02	A06X	3075704 Nova Scotia Co.
100 02 32 056 23 W5 02	A06X	3075704 Nova Scotia Co.
102 10 08 053 18 W5 00	A06X	3075704 Nova Scotia Co.
100 06 11 058 23 W5 02	A06X	3075704 Nova Scotia Co.
100 16 30 056 22 W5 00	A06X	3075704 Nova Scotia Co.
100 08 19 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 08 36 056 23 W5 00	A06X	3075704 Nova Scotia Co.
100 04 29 056 22 W5 00	A06X	3075704 Nova Scotia Co.
100 13 24 056 23 W5 00	A06X	3075704 Nova Scotia Co.

102 06 02 042 07 W5 02	0017	Imperial Oil Resources
100 10 16 058 22 W5 00	0X1J	Central Alberta Midstream
100 01 09 064 26 W5 02	0X1J	Central Alberta Midstream
100 06 18 061 09 W6 00	0F3F	Devon Canada
100 16 07 075 22 W5 00	A0EJ	Masters Energy Inc.
100 03 33 063 05 W6 00	A222	Trilogy Redsky Ltd.
100 06 32 057 17 W5 02	0N00	Primewest Energy Inc.
100 06 21 065 03 W6 00	A1DE	White Fire Energy Ltd.
100 03 29 065 08 W6 00	0J5Z	BP Canada Energy
100 13 12 059 21 W5 00	0J5Z	BP Canada Energy
100 03 19 045 18 W5 00	0246	Petro-Canada
100 01 02 040 09 W5 00	0246	Petro-Canada
102 10 13 041 10 W5 02	0246	Petro-Canada
100 08 11 047 16 W5 00	0PE3	Atco Midstream Ltd.
100 07 15 057 21 W5 00	0JT1	ExxonMobil Canada Energy
100 10 16 058 22 W5 00	0JT1	ExxonMobil Canada Energy
100 10 24 057 21 W5 00	0JT1	ExxonMobil Canada Energy
100 11 18 057 20 W5 00	0JT1	ExxonMobil Canada Energy
102 10 13 060 23 W5 02	0JT1	ExxonMobil Canada Energy
100 16 01 063 15 W5 02	AIT7	Canetic Resources Inc.
100 14 33 037 06 W5 00	0KR3	Northrock Resources Ltd.
100 11 08 064 07 W6 03	0KR3	Northrock Resources Ltd.
100 03 09 051 09 W5 00	0CW8	Compton Petroleum Corp.
100 14 10 041 09 W5 02	0E9L	ConocoPhillips Canada Energy Partnership
100 14 29 037 08 W5 02	0TX1	Blaze Energy Ltd.
102 10 25 035 07 W5 00	0TM9	NAL Resources Ltd.
100 16 11 058 19 W5 00	A162	Daylight Energy Ltd.
100 08 18 058 20 W5 04	A162	Daylight Energy Ltd.
100 08 27 049 15 W5 00	A162	Daylight Energy Ltd.
100 10 25 050 16 W5 02	A162	Daylight Energy Ltd.
100 14 31 054 27 W5 02	A162	Daylight Energy Ltd.
100 11 07 054 26 W5 02	A162	Daylight Energy Ltd.
100 06 16 047 14 W5 02	A162	Daylight Energy Ltd.
100 02 15 047 15 W5 00	A162	Daylight Energy Ltd.
100 06 07 049 14 W5 02	A162	Daylight Energy Ltd.
102 06 11 069 21 W5 02	0PL1	Ankerton Holdings Ltd.
100 03 34 063 02 W6 00	0HE9	Canadian Natural Resources Ltd.
100 04 15 059 24 W5 00	0HE9	Canadian Natural Resources Ltd.
102 11 32 040 08 W5 00	0TR8	Shiningbank Energy Ltd.
100 08 08 076 22 W5 00	A0C7	Galleon Energy Inc.
100 16 02 076 23 W5 00	A0C7	Galleon Energy Inc.
102 07 31 051 17 W5 00	0039	Talisman Energy Inc.
100 07 23 056 24 W5 00	0039	Talisman Energy Inc.
100 16 08 052 22 W5 00	0039	Talisman Energy Inc.

Value of Vertical Benefit

Vertical depth	Cumulative Value	Incremental Value
(metres)	($000)	($/metre)
2500	0	1000
3000	500	1000
3500	1000	1000
4000	1500	1300
4500	2150	1300
5000	2800	1600
5500 or deeper	3600	